DOE Exhibit 1.0

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

COMMONWEALTH EDISON COMPANY	)	
	)	
	)	
Petition for approval of delivery services	)	DOCKET NO. 01-0423
tariffs and tariff revisions and of residential	)	
delivery services implementation plan, and for	)	
approval of certain other amendments and	)	
additions to its rates, terms and conditions	)	

DIRECT TESTIMONY

AND ACCOMPANYING EXHIBITS

OF

DR. DALE E. SWAN

ON BEHALF OF

THE

UNITED STATES DEPARTMENT OF ENERGY

AUGUST 23, 2001

EXETER

ASSOCIATES, INC.
12510 Prosperity Drive
Suite 350

Silver Spring, Maryland 20904

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

COMMONWEALTH EDISON COMPANY	)	
	)	
	)	
Petition for approval of delivery services	)	DOCKET NO. 01-0423
tariffs and tariff revisions and of residential	)	
delivery services implementation plan, and for	)	
approval of certain other amendments and	)	
additions to its rates, terms and conditions	)	

DIRECT TESTIMONY

OF

DR. DALE E. SWAN

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A. My name is Dale E. Swan. I am a senior economist and principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland 20904.

Q. DR. SWAN, PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I hold a B.S. degree in Business Administration from Ithaca College. I attended a master's program in economics at Tufts University, and I hold a Ph.D. in economics from the University of North Carolina at Chapel Hill. Prior to my consulting work, I served as Assistant and Associate Professor on the economics faculties of several colleges and universities. I also served as staff economist with the Federal Energy Administration and with the Arabian American Oil Company. For the last 24 years, I have consulted on matters primarily related to the electric utility industry, the last 20 years with Exeter. Much of my work over the last two decades has concentrated in the areas of long-term electric power supply planning and contract negotiations for large power users, and on electric utility cost allocation and rate design. For much of this period, I have directed Exeter's utility support services projects with the United States Department of Energy (DOE). As part of this work, I have been responsible for technical supervision of Exeter's participation in DOE interventions in numerous rate cases, for the financial and locational assessment of transmission and generation projects, and for the negotiation of technical aspects of power supply and facilities contracts. In the last several years, my activities have also focused on the process of electric industry restructuring.

A complete copy of my resume is provided as an attachment to my testimony.

Q. HAVE YOU TESTIFIED IN OTHER REGULATORY PROCEEDINGS?

A. Yes. I have testified on a variety of topics relating to electric utilities in 48 proceedings before federal and state regulatory commissions. A complete list of the cases in which I have testified is provided as part of my resume.

Q. DR. SWAN, WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by DOE to address the reasonableness of Commonwealth Edison Company's (ComEd's) proposed RCDS rate design, specifically as it applies to large, high voltage customers such as DOE's Fermi National Accelerator Laboratory (Fermi) and the Argonne National Laboratory (Argonne).

Q. PLEASE SUMMARIZE THE ISSUES YOU ADDRESS AND THE CONCLUSIONS YOU REACH BASED ON YOUR ANALYSIS.

A. I first address the question whether class revenues and rates should be based on marginal costs, as they were for two decades prior to the Commission's decision in Docket No. 99-0117. I conclude that marginal costs should not be abandoned in favor of embedded costs, even if the Commission decides to use embedded costs to set rates for the few components of distribution service that will be competitive. I then turn to the calculation of the Rider HVDS credit for customers taking service at very high voltage levels. I conclude that the Company's proposed rates, based on an EPMC reconciliation of marginal costs, provide a reasonable match with the costs imposed by these customers, and so find acceptable the RCDS rates and the HVDS credit for large high voltage customers proposed by the Company. However, I also conclude that the embedded cost-based rates developed by the Company would continue to impose unfair overcollections on high voltage customers that do not use the distribution system. I therefore propose that these few customers be treated in a special manner by utilizing special facilities charges to recover the costs of the minor distribution equipment that they actually use, if the Commission directs the use of embedded cost-based rates. Finally, I address the use of ratcheted billing demands as the basis for recovering distribution facilities costs. I generally conclude that ratcheted demands can improve the intra-class match between costs and revenue recovery among customers with different load shapes, and find the Company's proposed use of a 12-month, 100 percent ratchet acceptable. I also conclude that the Company's development of the RCDS credit using unratcheted billing demands is incorrect, and I offer an alternative calculation that would not penalize high voltage customers if the Commission decides to retain an unratcheted rate design.

II. MARGINAL VS. EMBEDDED COSTS

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE BACKGROUND TO THE DEBATE REGARDING WHETHER CLASS REVENUES AND RATES SHOULD BE DETERMINED ON THE BASIS OF MARGINAL OR EMBEDDED COST.

A. With its Order 80-0546, the Illinois Commerce Commission became one of the leading proponents of the use of marginal costs for determining class revenue responsibilities and in designing rates in order to promote economic efficiency. Since that seminal decision, the Commission has steadfastly adhered to the primacy of marginal cost in rate design, despite numerous attempts by parties from all sides to restore embedded cost rate making. That commitment to marginal-cost pricing was abandoned in Docket No. 99-0117 when ComEd's delivery services tariffs were established.

Q. WHAT IS YOUR UNDERSTANDING REGARDING THE COMMISSION'S DECISION TO ABANDON MARGINAL COST PRICING IN DOCKET NO. 99-0117?

A. The Commission's explanation in that order is brief. It voiced concern that the use of marginal cost pricing "unduly protects an incumbent from competition." It also stated that the efficient price signals that are sent to potential competitors do not also serve to cause the incumbent utility to be efficient. The Commission was concerned that somehow there would be no symmetry in the efficient signals that would be received by the incumbent and by potential competitors. This concern seems to have been largely focused on those functional components of distribution service that are open to competition – namely the provision of billing and metering services. I infer from this brief discussion that the Commission seems to have concluded that the incumbent utility has an unfair competitive advantage if net avoided cost is used to set credits for a customer using an alternative supplier for metering and billing.

Beyond the explicit reason given by the Commission in its Order, the Commission did reference the objections that were raised to the use of marginal costs by Staff and by the Illinois Industrial Energy Consumers (IIEC). These parties, and especially Mr. Lazare for Staff, once again raised fundamental philosophical and theoretical objections to the use of marginal costs to set class revenues and rates. In addition, the Commission cited DOE criticism that the Company's marginal cost estimates were "seriously flawed," and it can be inferred that the Commission used the perceived DOE criticism as additional evidence that it should abandon marginal costing in favor of the use of embedded costs.

Q. DR. SWAN, DO YOU OR DOES DOE FAVOR THE ABANDONMENT BY THE COMMISSION OF MARGINAL COSTS TO DETERMINE CLASS REVENUES AND RATES?

A. No. I have testified on behalf of DOE in numerous ComEd cases over the last 20 years, beginning with Docket No. 82-0026, in favor of the use of marginal costs for the determination of class revenue responsibilities and rate design. I have also championed the use of the EPMC methodology for reconciling the embedded cost-based revenue requirement with marginal costs. My view, and the view of my client, has not changed over the past 20 years. Marginal costs remain the proper costs with which to determine rates. They provide the best set of rates to further economic efficiency and to promote an important aspect of equity – that customers should contribute revenue in proportion to the economic costs they impose on the system.

During all of those years, while advocating the use of marginal costs for rate design, I have also taken issue with errors, as I perceived them, in the way in which the Company or other parties estimated marginal costs. That is what I did in Docket No. 99-0117 regarding how the Company estimated the marginal distribution facilities cost for high voltage customers. My objection in that proceeding, and it remains my objection in this proceeding, was to the assignment of low voltage distribution facilities costs to high voltage customers that do not use those facilities. My objection was <u>not</u> to the use of marginal cost estimates of the facilities that those high voltage customers do use. The Commission should not use my limited criticism of a specific estimation technique, used to determine a minor portion of the total cost of distribution delivery service, as an indictment of the use of marginal cost in concept or the use of the majority of the Company's marginal cost estimates.

Q. WHAT COUNSEL CAN YOU OFFER TO THE COMMISSION REGARDING WHETHER IT SHOULD RETURN TO THE USE OF MARGINAL COSTS TO DETERMINE CLASS REVENUES AND RATES?

A. I cannot provide the Commission with a more eloquent or cogent explanation why marginal costs should be used than was offered by Professor Baumol in his rebuttal testimony in Docket No. 99 -0117. Nor can I provide a more succinct rejoinder to the notions raised by Staff witness Lazare than was provided by Dr. Jeff Makholm in his rebuttal testimony in the same proceeding. In my view, the testimony of these two witnesses should have eliminated any doubt that marginal costs are the proper costs to use in designing regulated rates, and should have laid to rest once and for all the peculiar notions raised by Mr. Lazare. I would urge the Commission to revisit the testimony of both of these witnesses.

Instead, permit me to comment on two slightly different aspects of the concerns explicitly identified by the Commission that may be of help to the Commission in reconsidering this issue. Let me begin by noting that the question of whether pricing should be done on the basis of net avoided cost for competitive services is essentially limited to certain metering and billing functions. Distribution delivery will remain a regulated monopoly service. Thus, we should focus our concern regarding the appropriateness of using embedded rather than marginal costs to those two functions.

It appears that the Commission believes that, because ComEd (as the incumbent utility)has an existing administrative infrastructure, it will maintain a competitive advantage if it provides a credit to the customer for taking this service from an alternative supplier based on its net avoided costs. The question at issue seems to me to be whether the Commission's objective should be to minimize costs to the customer or to provide a level playing field for ComEd's competitors. In the first instance, the objective should be to set maximally efficient rates, which are those based on marginal costs. That is the net avoided costs experienced by the Company. On the other hand, if the objective is to provide a level playing field for ComEd's competitors, then something close to ComEd's embedded cost might be appropriate for these competitive services.

In general, regulatory commissions have had as their two main objectives minimum costs for consumers and a fair return on the investment of the utility. I would suggest that the Commission's primary objectives have not changed. Minimizing costs to the ratepayer should remain the primary concern of the Commission. Indeed, the move to deregulation in most states has occurred because there was a growing conviction that competition can lead to lower costs to ratepayers. The Commission should be less concerned whether potential competitors can gain market share. The test of the benefits of open access is not how many customers are attracted away from the incumbent utility, but rather what prices those customers wind up paying, regardless by which supplier they are served.

Q. WHAT OTHER ASPECT OF THIS ISSUE DO YOU WISH TO BRING TO THE COMMISSION'S ATTENTION?

A. The Commission may choose to decide that credits due customers for taking metering and billing services from ComEd's competitors should be based on embedded costs as opposed to the net avoided costs of the Company, in order to provide a fillip to the competitive position of alternative suppliers -- a sort of infant industry argument. If so, that provides no basis for arguing that the rates of all of ComEd's regulated monopoly services should also be based on the incorrect average embedded costs. To do so would completely ignore the allocative efficiency function of prices and the requirement that the regulatory authority do its best to simulate what would occur in a competitive market. ComEd ratepayers must still make choices about how much delivery service to take, and those decisions will lead to the maximally efficient resource allocation if the rates upon which those decisions are made reflect the marginal costs of providing that service. If the Commission decides to abandon marginal costs as the basis for determining rates for the lion's share of the Company's services, in order to give a competitive fillip to competitors for a small portion of that service, we will have a classic example of "throwing the baby out with the bath water."

III. HIGH VOLTAGE DELIVERY SERVICE CREDIT

Q. DR. SWAN, PLEASE PROVIDE A BRIEF DESCRIPTION OF THE BACKGROUND RELATING TO THE PROVISION OF A CREDIT TO THE DISTRIBUTION FACILITIES CHARGE FOR HIGH VOLTAGE CUSTOMERS.

A. The Commission addressed the question of how to separate delivery facilities into distribution and transmission categories according to the FERC "7-Factor Test" in Docket No. 98-0894. The Company proposed what is sometimes referred to as the "last inch" approach, which was largely adopted by the Commission. Under this approach, all retail, end-use customers are defined as distribution customers, and it is assumed that, regardless of the size of the customer or the voltage delivery level, some small piece of equipment (the "Last Inch") has been installed only to provide that customer with service and has no system function. That last inch could be a jumper cable or an isolating switch, and since its only function is to provide the customer with service, it is distribution equipment, regardless of the voltage delivery level.

In Docket No. 99-0117, the Company proposed its RCDS rate for non-residential customers. For its largest commercial customers, with loads above 3,000 kW, the Company estimated the marginal distribution facilities cost using a regression estimate of the necessary investment per kW of peak demand, based on the hypothetical standard service investment for each customer in this category. Account was only taken of size. No regard was given to the fact that some high voltage customers do not use the distribution system, except for the minor pieces of "last inch" equipment. Nevertheless, rates were proposed by the Company as if these very large, high voltage customers actually used the distribution system.

Q. DID YOU FILE TESTIMONY IN DOCKET NO. 99-0117?

A. Yes. I filed testimony on behalf of the two DOE laboratories -- Fermi and Argonne.

Q. PLEASE SUMMARIZE THE GIST OF YOUR TESTIMONY IN DOCKET NO. 99-0117.

A. I demonstrated that both Fermi and Argonne are examples of large, high voltage customers that do not use the distribution system, save for the minor "last inch" pieces of equipment that were classified as distribution assets. I noted that Fermi is served by two 345 kV transmission lines owned by ComEd, which are classified as transmission assets. These two ComEd lines interconnect with two 345 kV lines owned by DOE. The lines are interconnected by four isolating switches that are owned by ComEd. These four switches make up the "last inch" of distribution equipment that serves Fermi. I also pointed out that Argonne is served by a looped 138 kV line that ComEd classified as a transmission asset. The "last inch" for Argonne is made up of two isolating switches and a few feet of cable. I testified that the Company was proposing to impose on these two laboratories distribution facilities charges in the neighborhood of $2.0 million a year for the use of these six switches and a few feet of cable, the total installation cost of which is unlikely to have exceeded $900,000. I went on to demonstrate that, at most, the carrying charge associated with these minor "last inch" pieces of distribution equipment could not exceed $135,000 a year for both laboratories. These points were unchallenged by the Company or other parties.

Q. WHAT RECOMMENDATION DID YOU MAKE TO THE COMMISSION IN THAT DOCKET?

A. I recommended that these high voltage customers that do not use the distribution system not be caused to pay monthly distribution facilities demand charges. Rather, I recommended that the distribution facilities charge be waived for these very high voltage customers, and that the cost of the "last inch" minor pieces of distribution equipment be recovered from these relatively few customers through monthly facilities charges, just as other dedicated equipment costs (such as transformers) are regularly recovered from large customers. Thus, qualifying high voltage customers taking service under Rate RCDS would pay for customer, metering and other appropriate RCDS charges plus the transmission charge in ComEd's Open Access Transmission Tariff (OATT) filed with the FERC, and special facilities charges for all "last inch" distribution equipment. In this way, these customers would pay the full cost of the "last inch" facilities dedicated to serve them, but would not be required to pay for the common distribution system that they do not use.

Q. HOW DID THE COMMISSION RULE ON THIS ISSUE IN DOCKET NO. 99-0117?

A. The Commission stated that it understood the concerns expressed by DOE and other intervenors. Nevertheless, it accepted the Company's proposal. This was based on the Commission's belief that the objecting parties failed to provide a superior recommendation and that there is a high enough correlation between size and voltage delivery level to conclude that designing rates for different size categories of customers meets the requirement in the governing legislation that, "In establishing charges, terms and conditions of service, the Commission shall take into account voltage level differences."

Q. WHAT HAS THE COMPANY PROPOSED IN THIS PROCEEDING REGARDING THE CHARGE FOR DISTRIBUTION FACILITIES FOR HIGH VOLTAGE CUSTOMERS?

A. In this case the Company has again calculated the distribution facilities demand charge for large customers with 3,000 kW and higher based on a regression estimate of the distribution investment costs required to provide these customers with standard service. Then, the Company estimates the cost differential associated with providing standard service hookups to high voltage customers served at 69 kV and higher compared to customers taking service below 69 kV. This differential is used to calculate a High

Voltage Distribution Services (HVDS) credit. The charge proposed by the Company for customers with loads above 10,000 kW is $3.05 per kW-month. The credit, provided in Rider HVDS, is proposed at $2.65 per kW-month. This charge and credit are based on the Company's proposed EPMC application of the estimated marginal costs of distribution service. In addition, qualifying high voltage customers would continue to receive the Rider 8 credit of $.20533 per billing kW for owning their own transformers.

Q. DOES THE PROVISION OF THE HVDS CREDIT MEET YOUR CONCERNS REGARDING THE OVERCHARGING OF HIGH VOLTAGE CUSTOMERS SUCH AS FERMI AND ARGONNE FOR THE DISTRIBUTION SYSTEM THAT THEY DO NOT USE?

A. The Company's proposed HVDS credit, in conjunction with the Rider 8 credit, goes a long way toward reducing the subsidy that was being paid for by high voltage customers like Fermi and Argonne. Applying the Company-proposed RCDS rates and the HVDS and Rider 8 credits to the Fermi and Argonne forecasted billing units indicates that DOE will pay distribution facilities charges of approximately $238,000 a year, while the carrying cost of the "last inch" facilities actually serving Fermi and Argonne is estimated not to exceed $135,000 a year. Thus, under the improved Company proposed rate design, DOE would only be overpaying by an estimated $100,000 a year. DOE is prepared to support this proposed rate design for the class of customers above 10,000 kW.

That, of course, assumes that the Company's proposed marginal cost-based rates are adopted. If the embedded cost-based rates that the Company calculated for Staff in response to ML-1 were adopted, the cost to DOE would be approximately $1.6 million a year, an annual overrecovery of costs from these two national laboratories of $1.5 million. This result would hardly meet the principle of cost-based rates. It would be somewhat gratifying, nevertheless, that the Company has finally recognized that high voltage customers deserve some kind of consideration when it comes to recovering the costs of the lower voltage distribution system that they do not use.

Q. WHY ARE THE DOE LABORATORIES OVERCHARGED BY SO MUCH WHEN THE DISTRIBUTION FACILITIES CHARGE AND THE HVDS CREDIT ARE BASED ON EMBEDDED COST?

A. There are two reasons. First, use of the Company's embedded cost study to determine class revenues and design rates, as developed by the Company in its response to Staff Data Request ML-1, shifts $57.5 million to non-residential classes, an increase of nearly 8 percent. The class of customers above 10,000 kW would receive an additional $28.7 million, a revenue requirement nearly 60 percent higher than under marginal cost-based rates. Thus, assigning responsibility for the cost of the distribution system under an embedded cost-based method will exacerbate the amount by which customers that do not use the distribution system are overcharged.

The second reason has to do with the way in which the HVDS credit is calculated, for that is the primary mechanism by which these high voltage customers get any relief from the cost of the distribution system they don't use. The calculation of the embedded cost-based HVDS credit for customers in the Over 10,000 kW class is provided in Attachment 3 to the response to ML-1, which is provided as Exhibit_(DOE-1). The method takes the distribution costs by type of facility that were allocated to the class as a whole, and further allocates these costs to customers with service at or above 69 kV, and to customers with service below 69 kV. The difference in the cost per kW between the high voltage group and the low voltage group is used as the HVDS credit.

It is instructive to examine the distribution facilities costs that are allocated to the high voltage group. It is allocated 100 percent of high voltage electric service station (HV ESS) cost ($12,825,925) and about half ($1,510, 827) of high voltage distribution lines cost. Finally, this high voltage group is allocated $105,689 of high voltage distribution substation cost. In response to City of Chicago COC 3.230, the Company explains which customers use HV ESS and high voltage distribution substations. This response is provided as Exhibit_(DOE-2). The Company states that a high voltage electric service station "is a substation used to supply an individual customer from high voltage lines (69,000 Volts or higher)." The Company further explains that a "high voltage distribution substation . . . reduces high voltages (69,000 Volts or 138,000 Volts) to a distribution voltage, (69,000, 34,000 or 12,500 Volts)."

While it may prove appropriate to impose these costs on many high voltage customers, it is clearly inappropriate to do so for customers like Fermi and Argonne. To my knowledge, neither of these national laboratories uses ComEd high voltage electric service stations or high voltage distribution substations. Both Fermi and Argonne maintain their own substations and take service directly from high voltage transmission lines. The ComEd lines that serve these two laboratories are classified by ComEd as transmission lines, not as high voltage distribution lines. In short, the credit is based on the difference in the average cost of facilities used by low voltage customers and the cost of facilities for high voltage customers, which are not used by Fermi and Argonne. Fermi and Argonne incur the continuing cost of owning, maintaining and operating their own substation facilities which permits them to take service from ComEd straight from the transmission system. The Company's rate design would impose some of these costs again on Fermi and Argonne, which is patently unfair.

Q. HOW DO YOU PROPOSE THAT THE RCDS RATES BE MODIFIED IF THE COMMISSION DECIDES THEY SHOULD BE BASED ON EMBEDDED COSTS?

A. The proponents of embedded costs argue that they are the "actual" costs incurred by the utility, and that rates based on embedded costs reflect the actual costs incurred to provide the customer with service. It is clear that customers like Fermi and Argonne will be caused to bear the costs of facilities they do not use if the embedded cost-based distribution facilities charge is approved by the Commission. That is, the rates for these customers do not reflect the "actual" costs incurred to provide these customers with service. This is probably due to the fact that the DOE laboratories are different than most other customers that would qualify for the HVDS credit. If that is the case, then the simple solution is to treat separately the few customers like Fermi and Argonne that do not use the facilities that are allocated to the larger group of high voltage customers in the Company's calculation of the HVDS credit.

Q. HOW WOULD YOU ACCOMPLISH THIS?

A. Those few customers that do not use the facilities allocated to the high voltage group, but who actually take service directly from the transmission system, should not be required to pay the distribution facilities demand charge, nor receive the HVDS credit and transformer ownership credit. Rather, a special facilities charge should be determined for each of these customers that recovers the costs of the various "last inch" distribution equipment that is actually used to serve these customers. Thus, these customers would be required to pay the customer charge, the meter service charge, the special facilities charge for "last inch" equipment, the ComEd open access transmission tariff charges and other rider charges that are not related to the recovery of distribution facilities costs. In short, these customers would be caused to pay for the "actual" embedded costs of the services and facilities that are incurred by the Company to provide these customers with service.

Q. IS IT FEASIBLE TO ACCOUNT FOR THESE EXCEPTIONS TO THE RCDS RATE?

A. I believe so. It would require determining the cost of the special "last inch" distribution facilities installed to serve each of the qualifying high voltage customers. However, that would not appear to be particularly difficult. There are only 52 customers in total in all rate classes that qualify for the HVDS credit, and the number of customers that would qualify for this special treatment is probably considerably less than 52. Moreover, the inventory of these "last inch" facilities must have been assembled for the functional separation between transmission and distribution categories that took place during Docket No. 98-0894.

Q. WOULD RATES HAVE TO BE ADJUSTED FOR OTHER CUSTOMERS IN THE CLASSES WHERE THESE SPECIAL HIGH VOLTAGE CUSTOMERS RESIDE?

A. Yes. The distribution facilities charge and the HVDS credit would both need to be recalculated by eliminating the loads of the special customers. Both the charge and the credit would increase. This will have the effect of shifting the overcharges that these special customers would pay under the Company's embedded cost-based rates onto the remaining customers in the class. That simply follows from the principle of cost-based rates and would be an equitable solution.

IV. <u>THE COMPANY-PROPOSED 100% RATCHET</u>

Q. HAS THE COMPANY PROPOSED THAT THE DISTRIBUTION FACILITIES CHARGE BE DESIGNED ON THE BASIS OF A RATCHETED BILLING DEMAND?

A. Yes. The Company has designed the distribution facilities demand charge using 100 percent, 12-month ratcheted billing demands for all customer classes with demand meters. This means that the facilities charge for any given month will be based on the highest demand registered during the Company's "Demand Peak Periods" during the 12-month period ending with the billing month in question.

Q. DOES THE CURRENT RCDS RATE CONTAIN A RATCHETED DEMAND FEATURE?

A. No. This feature was proposed by the Company in Docket No. 99-0117, but it was rejected by the Commission. According to the Order in that proceeding, the Commission's primary concern regarding the use of a demand ratchet appears to have been that it, "prevents customers from having control over a substantial portion of their bills for a year." In particular, the Commission was concerned that the use of the ratchet would force customers to continue to pay high demand charges "even if there is an economic downturn, while the utility is insulated from the same downturn."

Q. DR. SWAN, WHAT IS YOUR OPINION OF THE USE OF DEMAND RATCHETS?

A. A demand ratchet can be a useful device to track differences in costs among customers in the same rate class. In particular, when costs are determined by the maximum demand of the customer, ratchets can help match revenue contributions to costs within customer classes. Distribution costs are largely driven by customer peak demands over a fairly long period of time. That is, if a customer's annual peak occurs every July, while its peaks in every other month are significantly below its July peak, the cost the Company must incur to provide service to that customer is determined by the annual peak demand. The cost does not fall in the other months because the equipment necessary to provide that customer with service is sized to meet the peak load.

It is true that, for distribution facilities farther upstream from the customer meter that meet the requirements of many customers, demand diversity among customers should theoretically be taken into account. That means that the equipment must be sized to meet the local neighborhood annual coincident peak demand placed on that equipment, rather that the sum of the non-coincident loads of all of the customers being served by that equipment. In actuality, local coincident peaks are not data that are readily available in designing rates. Moreover, the amount of diversity that is expected to exist on local neighborhood distribution systems is not great. Thus, for rate design purposes, it is generally accepted that the cost of distribution facilities is largely driven by non-coincident demands of classes, and so the non-coincident peak demands of the customers within those classes.

Q. HOW IS A DEMAND CHARGE BASED ON RATCHETED BILLING DEMANDS SUPERIOR IN TRACKING COSTS AMONG CUSTOMERS IN A GIVEN CLASS COMPARED TO A CHARGE BASED ON UNRATCHETED BILLING DEMANDS?

A. Costs that are driven by non-coincident demands are presumably properly allocated or assigned to classes on the basis of class NCPs. However, if the rate schedule for the class uses current monthly (unratcheted) billing demands, costs are shifted from customers with unstable month-to-month peaks to customers with stable month-to-month peaks. A ratchet, such as the 12-month, 100 percent ratchet proposed by the Company, will assign the class costs among customers based on their maximum annual demands, in the same way that the costs were allocated to the class. If there were no differences in the ratio of the annual peak to the average monthly peak among the customers in the class, then there would be no need for the ratchet. However, as long as there exists variation in load shapes among customers served under a given rate schedule, there will be variations in cost responsibility, some of which are properly captured by the use of ratcheted billing demands.

Q. WHAT ABOUT THE CONCERNS RAISED BY THE COMMISSION IN ITS 99-0117 ORDER?

A. I understand the Commission's concerns, but I respectfully suggest that they are misplaced. We are not talking about residential customers. We are talking about businesses for the most part. Business concerns do, or should, understand the notion of contracts and fixed costs. If a business firm leases a building, it generally does not expect the landlord to reduce its rent during an economic downturn to reflect the fact that less space is required because the firm has laid off a number of workers. The fixed monthly lease payments will continue according to the lease contract. That is true for most services that are purchased by businesses, the costs of which are largely fixed and the payment for which are set by contract. The situation is no different in the case of ComEd using a 12-month ratcheted demand charge, except that the fixed charge lasts only a year, whereas most business leases fix rents for periods that often run five to 10 years, or longer.

The Commission also seemed to be concerned that the use of ratcheted billing demands would insulate the utility from revenue losses resulting from economic downturns. The Commission is correct. But, that is true with any contractual arrangement that is entered into to cover the risks associated with investments that are made on behalf of a customer, the costs of which are largely fixed across the business cycle. The question is who should bear that risk? The market generally requires the customer to bear that risk through appropriate contract arrangements. To the extent that regulation attempts to mirror the results that would obtain in a competitive market, then it is fully appropriate to impose these fixed costs on customers through a type of quasi-contract obligation – ratcheted demand charges.

What the Commission does fail to note in the 99-0117 Order is that it is certain that costs will be unfairly shifted from customers with unstable month-to-month peaks to customers with stable monthly peaks under a rate design based on unratcheted billing demands. That will definitely penalize a customer such as Fermi National Accelerator Laboratory, which forecasts a constant monthly peak of 58 MW for the next 12 months.

Q. DO YOU RECOMMEND THAT THE COMPANY'S PROPOSED RATCHETED RATE DESIGN FOR RATE RCDS BE ADOPTED?

A. I can support the adoption of a ratcheted rate design in recovering the distribution facilities costs in Rate RCDS. However, given the Commission's decision on this issue in Docket No. 99-0117, I am more concerned that the Company properly design an unratcheted distribution facilities charge for classes that contain customers eligible for the HVDS credit.

V. HVDS CREDIT WITH UNRATCHETED BILLING DEMANDS

Q. IF THE COMMISSION CONCLUDES THAT THE DISTRIBUTION FACILITIES CHARGE SHOULD BE DETERMINED ON THE BASIS OF UNRATCHETED BILLING DEMANDS, HOW SHOULD THE HVDS CREDIT BE DETERMINED?

A. The guiding principle in calculating rates using ratcheted and unratcheted billing demands is revenue neutrality. That is, the revenue responsibility of a class, or of large groups within a class, ought to remain about the same whether ratcheted or unratcheted billing demands are used to design the unit charges. Since the class or group revenue responsibility remains the same, then clearly the unit charges must vary when the billing units vary. More specifically, if the same revenue must be collected from fewer unratcheted billing demands, then the unit charges must rise. That should apply to credits as well as charges.

Q. HAS THE COMPANY PROVIDED THE CALCULATED RATES FOR CUSTOMERS WITH DEMAND CHARGES BASED ON UNRATCHETED BILLING DEMANDS?

A. Yes. The Company provided the rates that it would presumably propose if it were directed by the Commission to use unratcheted billing demands in response to ARES No. 2.34 and to DOE 2-4. The Company did not develop these unratcheted rates as part of its direct case presumably because it believes that it is appropriate to use ratcheted billing demands.

Q. HAS THE COMPANY PROPERLY DESIGNED THE DISTRIBUTION FACILITIES CHARGE AND THE HVDS CREDIT BASED ON UNRATCHETED BILLING DEMANDS FOR CLASSES WHICH CONTAIN CUSTOMERS WITH SERVICE AT HIGH VOLTAGE?

A. No. The Company has incorrectly retained the same $2.65 per kW-month HVDS credit that it calculated using ratcheted billing demands. This is incorrect. The HVDS credit must rise along with the distribution facilities charge when moving to rates based on lower unratcheted demands. The HVDS credit was originally calculated based on the reduced investment costs per kW of maximum annual demand associated with providing service to high voltage customers. Thus, this credit initially reflected the differential costs of serving high voltage and lower voltage customers based on ratcheted billing demands. If another definition of demand is used, then the credit must be adjusted accordingly.

Q. DOES THE COMPANY'S APPROACH MEET THE REVENUE NEUTRALITY PRINCIPLE?

A. No. As is shown in Exhibit_(DOE-3), the group of 32 high voltage customers that are part of the 10,000 and above class have an annual revenue requirement of $5.5 million under the Company's proposed rates based on ratcheted billing demands. This same group of customers would have an annual revenue requirement of $10.9 million under the Company's approach to designing rates using unratcheted billing demands. This is an increase of over 100 percent in this customer group's revenue responsibility, which is hardly a revenue neutral approach to rate design.

Q. HAVE YOU DEVELOPED A RATE DESIGN FOR HIGH VOLTAGE CUSTOMERS THAT RECEIVE THE HVDS CREDIT BASED ON THE USE OF UNRATCHETED BILLING DEMANDS?

A. I have calculated the proper distribution facilities charge and the associated HVDS credit for customers in the 10,000 kW and higher class, based on the unratcheted billing demands provided by the Company. These calculations are provided on page 1 of

Exhibit_(DOE-4). The same procedure would apply to all other classes with customers that qualify for the HVDS credit.

Q. PLEASE DESCRIBE YOUR CALCULATION OF THESE UNRATCHETED RATES FOR THE 10,000 KW AND ABOVE CLASS.

A. I begin with the revenue responsibility of the high voltage customers under the Company's ratcheted rate design. That is $5,358,628. Next I calculate what the net charge must be for the high voltage customers under an unratcheted design to recover the same revenue as under the ratcheted rates. That is $.52 per kW-month. I next determine what the distribution facilities charge revenue requirement is for the low voltage customers under the Company's ratcheted rate design and divide that by the reduced unratcheted billing demands of the low voltage group, to arrive at the distribution facilities unit charge for low voltage customers based on unratcheted billing demands. That is $4.22/kW-month. The HVDS credit is the difference between the $4.22 rate for low voltage customers and the $.52 net rate for high voltage customers, or $3.70/kW-month.

The second page of Exhibit_(DOE-4) provides a revenue reconciliation between the class revenue responsibility under the ratcheted and unratcheted rate designs. The resulting revenues differ only by amounts due to rounding of the unit charges.

Q. HOW DO FERMI AND ARGONNE FARE UNDER YOUR DESIGN OF UNRATCHETED RATES COMPARED TO THE COMPANY'S RATCHETED AND UNRATCHETED RATES?

A. This comparison is provided in Exhibit_(DOE-5). Both Fermi and Argonne have much more stable demands than does the class as a whole, which will cause the revenue recovery from these two customers to increase when one moves from a ratcheted to an unratcheted rate design. The annual distribution facilities charge revenue increases by $4,404 or 2 percent for Argonne and by $83,520 or 29 percent for Fermi when moving from the Company's ratcheted rates to my unratcheted rates. That is a reasonable reflection of the intra-class revenue shift from customers with unstable demands to customers with stable demands. The annual increase is $222,733 or 103 percent for Argonne and $451,468 or 159 percent for Fermi when moving to the Company's unratcheted rate design. These enormous increases are the result of an improper and insufficient HVDS credit, and not simply the usual intra-class revenue shift from customers with highly seasonal fluctuating demands to customers with stable month-to-month demands.

Q. WHAT RECOMMENDATION DO YOU HAVE FOR THE COMMISSION IF IT DECIDES THAT RATES SHOULD BE BASED ON UNRATCHETED BILLING DEMANDS?

A. The Commission should require the Company to recalculate the rates and the HVDS credit in every class which contains customers eligible for the HVDS credit, using the method I present in Exhibit_(DOE-4).

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

ATTACHMENT

RESUME

OF

DR. DALE E. SWAN

DALE E. SWAN

Dr. Swan is a senior economist and principal at Exeter Associates, Inc. His areas of expertise include energy supply and demand analysis, electric industry restructuring, utility cost allocation and rate structure design, utility contract negotiation, antitrust policy, and public utility regulation.

Dr. Swan has given expert testimony in utility rate cases before the Federal Energy Regulatory Commission and before numerous state regulatory commissions. He has testified on marginal and embedded costing, rate structure design, long-term demand forecasting, short-term sales forecasts, the treatment of off-system sales, electric industry restructuring, and antitrust considerations. He has directed major projects for the U.S. Department of Energy, the U.S. Air Force, and the Rhode Island Public Utilities Commission on such issues as alternative power supply options and innovative rate structure experiments and implementation, and he has prepared and presented seminars and workshops on such issues as marginal costing, rate design, and interruptible rates for, among others, the National Regulatory Research Institute, the U.S. Department of Energy, and for state commission staffs in Maryland, Minnesota, and New Hampshire.

Dr. Swan has assisted federal agencies in the negotiation of electric power supply contracts and in the financial and locational assessment of transmission and generation projects; he has also prepared reports to several federal and state agencies on costing methods, rate design, the demand for electric power, PURPA requirements, bulk power supply planning, stranded cost recovery, standby rates, value-of-service pricing, the use of special contracts, and other issues. Recently, he has also acted as an Advisor to the Maine Public Utilities Commission in the restructuring proceedings for the three investor-owned Maine electric utilities.

Education:

B.S. - (Business Administration) - Ithaca College, 1962.

M.A. Program in Economics - Tufts University, 1962-63.

Ph.D. - (Economics) - University of North Carolina at Chapel Hill, 1972.

Previous Employment:

1976-1980	**-**	**Senior Economist, J.W. Wilson & Associates, Inc.**
1974-1976	**-**	**Associate Professor of Economics, Jacksonville State University**
1974	**-**	**Economist, Office of Energy Systems, Federal Energy Administration**

1973	**-**	**Staff Economist, Economics Department, Arabian-American Oil Company**
1968-1973	**-**	**Assistant and Associate Professor of Economics, Hampden-Sydney College**
1969-1973	**-**	**Visiting Assistant Professor of Economics, Randolph-Macon Womans College**
1967-1968	**-**	**Assistant Professor of Economics, Southern Methodist University**
1966-1967	**-**	**Visiting Assistant Professor of Economics, North Carolina Central University**
1963-1964	**-**	**Market Research Analyst, The Carter's Ink Company**

Previous Professional Work:

At J.W. Wilson & Associates, Inc., Dr. Swan had primary responsibility for the development and direction of several of the firm's largest projects relating to the electric utility industry and costing and rate design issues in particular. Dr. Swan also had major responsibilities in the areas of cogeneration, antitrust, PURPA requirements, and technical assistance to state regulatory authorities under DOE grant programs.

At the Federal Energy Administration, Dr. Swan participated in the development of a National Energy Accounting System, similar to and compatible with the National Income and Product Accounts and the U.S. Input/Output Accounts. During his tenure at Jacksonville State University, Dr. Swan continued with this work as a consultant to the FEA.

While with ARAMCO, Dr. Swan prepared financial analyses of capital investment alternatives, developed cost trend estimates for price negotiations, and initiated the preparation of revised price trend factors to be used for budgeting purposes.

At Carter's Ink Company, Dr. Swan was responsible for conducting new product and new market research for the Director of Marketing, including consumer attitudinal studies on new product and packaging designs.

Dr. Swan has taught both graduate and undergraduate courses during his academic career. Among the courses he has taught are Microeconomic Theory, Industrial Organization, Economic History, International Trade, Economic Development, and Principles of Economics.

Selected Publications, Papers, and Reports:

"Strategic Options in Planning for the Long-Term Power Requirements of the DOE/OAK Laboratories." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, September 1998.)

"Utility Options Study: Rocky Flats Environmental Technology Site." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, March 1997.)

"Competitive Acquisition of Power by Federal Agencies: Current Possibilities and Future Prospects." (Presented before the Competitive Power Congress, Philadelphia, Pennsylvania, July 21, 1995.)

"Standby Rate Rulemaking: A Discussion of Issues and Proposed Positions." (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 10, 1995.)

"Stranded Cost Rulemaking: A Discussion of Issues and Proposed Positions." (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 3, 1995.)

Superconducting Super Collider Permanent Power Supply: A Preliminary Consideration of Supply Alternatives." (Exeter Associates, Inc., revised draft report prepared for the U.S. Department of Energy, Office of Organization, Resources and Facilities Management, March 1992.)

"The Potential Savings Associated with Exporting EBR-II Energy from the Idaho National Engineering Laboratory to Another Federal Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, March 1991.)

"Planning and Preparing a Utilities Options Study," in Utilities Planning and Management for Department of Energy Facilities. (U.S. Department of Energy, February 1990.)

"An Evaluation of the Financial Benefits to the United States Government from Using $175 Million of the TRNLC Fund to Purchase Generating Capacity to Reduce Power Costs of the Superconducting Super Collider." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, January 1990.)

"Power Supply Arrangements at Brookhaven National Laboratory." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, October 1989.)

"Electric Power Supply Options for the Continuous Electron Beam Accelerator Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, July 1989.)

"The Potential Future Value of Byproduct Steam from a New Production Reactor Based on Four Alternative Technologies and Three Alternative Sites," with Steven Estomin and Richard Galligan. (Exeter Associates, Inc. for the U.S. Department of Energy, August 1988.)

"An Analysis of the Optimal Allocation of Available Western Area Power Administrative Preference Power Among Three Northern California Laboratories," with Charles E. Johnson. (Exeter Associates Inc. for DOE San Francisco Operations Office, March 1986.)

"Report on the Role of Special Contracts in Electric and Gas Utility Ratemaking." (Exeter Associates, Inc. for the U.S. Postal Service, February 1984.)

"The Electric Utility Industry," in <u>Study of Pricing Precedents in the Public Utility Industry</u>. (Exeter Associates, Inc., for the U.S. Postal Service, February 1984.)

"State Regulatory Attitudes Toward Fuel Expense Issues," with Matthew I. Kahal, Report to the Electric Power Research Institute, June 1983.

"A Summary and Analysis of Federal Legislation Affecting Electric and Gas Utility Diversification." (Exeter Associates, Inc. for Argonne National Laboratory, August 1981.)

"Average Embedded Cost Studies as the Basis for Rate Designs Consistent with the Goals of the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 6, 1981.

"Analysis of the Major Comments Made on the ERA Proposed Voluntary Guideline for the Cost-of-Service Standard Under the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 1981.

"The Rhode Island - DOE Electric Utilities Demonstration Project." Final Report - November 1980, and three Interim Reports in July 1978, November 1979, and July 1980. (J.W. Wilson & Associates, Inc. for the Rhode Island Division of Public Utilities and Carriers.)

"An Evaluation of Power Supply Planning by the Six Investor-Owned Electric Utilities in South Dakota," with Ralph E. Miller. (J.W. Wilson & Associates, Inc. for the South Dakota Public Utilities Commission, 1977.)

<u>The Structure and Profitability of the Antebellum Rice Industry: 1859</u>. (New York: Arno Press, 1975.)

"The Structure and Profitability of the Antebellum Rice Industry: 1859." <u>Journal of Economic History</u>, (December 1972.)

"The Productivity and Profitability of Antebellum Slave Labor: A Micro Approach," with James D. Foust. Agricultural History, (January 1970). Later published in William N. Parker (ed.), The Structure of the Cotton Economy of the Antebellum South. (New York: Agriculture History Society, 1970.)

Participation in Conferences, Seminars and Workshops:

Competitive Power Congress, 1995.

Department of Energy Utility Conferences, 1985, 1986, 1990, 1992, 1995, 1996, 1997.

DOD/DOE Combined Utility Planning Conference, March 1987.

American Historical Association Meetings, 1981.

National Regulatory Research Institute Workshop on Time-of-Use Rates, September 1979.

National Regulatory Research Institute State Needs Assessment Conference, August 1979.

Southern Economic Association Meetings, 1969, 1972, 1975.

Economic History Association Meetings, 1972.

Expert Testimony

Presented by Dale E. Swan

1. **Before the Public Utilities Commission of the State of Ohio, Case No. 78-676-EL-AIR, on marginal costs and electric rate structure design.**

2. **Before the Public Utilities Commission of the State of South Dakota, Docket No. 3362, on marginal costs and electric rate structure design.**

3. **Before the Public Utilities Commission of the State of South Dakota, Docket Nos. F-3240 and F-3241, on electric rate structure design.**

4. **Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1311, on the design of a proposed inverted rate structure experiment.**

5. **Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1262, on the operation and the results of a time-of-day rate experiment.**

6. **Before the Public Utilities Commission of the State of South Dakota, Docket No. F-3116, on test year sales forecasts.**

7. **Before the Public Utilities Commission of the State of Montana, Docket No. 6441, on test year sales forecasts.**

8. **Before the Public Service Commission of the State of Maryland, Case No. 6807, on long-term demand forecasting methodology.**

9. **Before the Public Service Commission of the State of New York, Docket No. 27136, on test year sales forecasts and economic impact.**

10. **Before the Federal Energy Regulatory Commission, Docket No. ER77-530, on retail competition in the Ohio electric power market.**

11. **Before the Public Service Commission of the State of Maryland, Case No. 7441 (Phase III), on electric rate structure design and PURPA ratemaking standards.**

12. **Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1591, on class revenue requirements and electric rate structure design.**

13. **Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1606, on PURPA Section 111 standards, class cost-of-service, and rate structure design.**

14. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1605, on class revenue requirements and electric rate structure design.

15. Before the Public Utilities Commission of the State of Idaho, Case No. U-1006-185, on class revenue requirements and rate design.

16. Before the Illinois Commerce Commission, Docket No. 82-0026, on marginal-cost-based class revenue responsibilities and rate design.

17. Before the Public Utilities Commission of the State of Idaho, Case No. U-1009-120, on contractual arrangements, embedded-cost-based class revenue requirements, and rate design.

18. Before the Public Utilities Commission of the State of Maryland, Case No. 7695, on proper electric class cost-of-service methodologies.

19. Before the Public Service Commission of Nevada, Docket No. 83-707, on marginal-cost-based class revenue responsibilities and rate design.

20. Before the Illinois Commerce Commission, Docket No. 83-0537, on marginal-cost-based class revenue responsibilities, rate design, and rate schedule qualification standards.

21. Before the Public Utilities Commission of the State of Idaho, Case No. U-1009-137, on jurisdictional separations, embedded class cost-of-service studies, interruptible service credits, and class revenue requirements.

22. Before the South Carolina Public Service Commission, Docket No. 84-122-E, on embedded class cost-of-service methodologies, class revenue requirements, and rate design.

23. Before the Public Utilities Commission of the State of Idaho, Case No. U-1500-157 (May 1985), on the public interest aspects of declaring one utility as the sole supplier of the Idaho National Engineering Laboratory.

24. Before the Illinois Commerce Commission, Docket Nos. 83-0537 (Step 2) and 84-0555 (Consolidated), June 1985, on marginal-cost-based class revenue responsibilities and rate design.

25. Before the Public Utilities Commission of the State of Idaho. Case No. U-1006-265A (May 1987), on embedded class cost-of-service studies, class revenue requirements, and rate design.

26. Before the Public Utilities Commission of the State of Maine, Docket No. 86-242 (August 1987), on by-pass and incentive rate discounts for large industrial customers.

27. **Before the Illinois Commerce Commission, Docket No. 87-0427, (February and April 1988), on marginal-cost-based class revenues, Ramsey pricing considerations, and industrial rate design.**

28. **Before the Illinois Commerce Commission, Docket No. 87-0695, (April 1988), on marginal-cost-based class revenues, Ramsey pricing issues, and industrial rate design.**

29. **Before the Indiana Utility Regulatory Commission, Cause No. 37414-S2 (October 1989), on ratemaking treatment of off-system sales, embedded cost-of-service study, and rate design.**

30. **Before the Public Utilities Commission of the State of Maine, Docket 89-68 (January 1990), on measurement and use of marginal costs for determining class revenues.**

31. **Before the Federal Energy Regulatory Commission, Docket No. EC90-10-000, et. al. (May 1990), with Matthew I. Kahal, on the potential effects of the Northeast Utilities acquisition of Public Service New Hampshire on market concentration and competition in the New England bulk power market.**

32. **Before the Illinois Commerce Commission, Docket No. 90-0169 (August and October 1990), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.**

33. **Before the Public Service Commission of Nevada, Docket Nos. 91-5032 and 91-5055 (September 1991), on the estimation of marginal costs, class revenue responsibilities and rate design for large power users.**

34. **Before the Public Service Commission of Nevada, Docket No. 92-1067 (May 1992), on the estimation of marginal costs, the cost of providing interruptible power, class revenue responsibilities, and rate design for large power users.**

35. **Before the Public Utilities Commission of the State of Maine, Docket No. 92-095 (February 1993), Affidavit regarding the efficacy of rate discounts in attracting new business.**

36. **Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (June 1993), on revamping of the rate structure to meet competition for sales.**

37. **Before the Public Utilities Commission of the State of Maine, Docket No. 92-345 (August 1993), with Marvin H. Kahn, on price cap mechanisms as an alternative form of regulation.**

38. **Before the Public Service Commission of Nevada, Docket No. 92-9055 (October 1993), on franchise rights to serve a large DOE customer.**

39. **Before the Illinois Commerce Commission, Docket No. 94-0065 (June 1994), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.**

40. **Before the Public Service Commission of Nevada, Docket No. 93-11045 (June 1994) on the estimation of marginal costs, environmental externality adders, competition for loads, and class revenue responsibilities.**

41. **Before the Idaho Public Utilities Commission, Case No. IPC-E-94-5 (November 1994), on embedded class cost allocation and class revenue responsibilities.**

42. **Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (II) (March 1995), on the estimation of marginal distribution demand and customer costs.**

43. **Before the Public Utilities Commission of the State of Maine, Docket No. 95-052 (RD) (October 1995 and January 1996), with Daphne Pscharopoulos, on the estimation of marginal costs as the basis for class revenues and rate design.**

44. **Before the Public Service Commission of Nevada, Docket No. 96-7020 (November 1996), on the estimation of marginal costs, class revenue responsibilities, and the reasonableness of fixed, up-front facilities charges.**

45. **Before the Public Service Commission of Montana, Docket No. 97.7.90 (November 1997 and March 1998), on aspects of Montana Power Company's proposed restructuring plan.**

46. **Before the Illinois Commerce Commission, Docket No. 99-0117 (April 1999), on the design of distribution delivery rates for Commonwealth Edison Company.**

47. **Before the Public Utilities Commission of Nevada, Docket Nos. 99-4005 and 99-4006, (November 1999), on the design of an electric distribution service tariff for Nevada Power Company.**

48. **Before the Public Utilities Commission of Nevada, Docket No. 99-7035 (January and February 2000), on Nevada Power proposed revision to its base rates and deferred energy adjustment rates, including the recovery and allocation of deferred capacity costs and the appropriate calculation of annualized fuel and purchased power costs.**

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

COMMONWEALTH EDISON COMPANY	)	
	)	
	)	
Petition for approval of delivery services	)	DOCKET NO. 01-0423
tariffs and tariff revisions and of residential	)	
delivery services implementation plan, and for	)	
approval of certain other amendments and	)	
additions to its rates, terms and conditions	)	

EXHIBITS ACCOMPANYING

THE

DIRECT TESTIMONY

OF

DR. DALE E. SWAN

ON BEHALF OF

THE

UNITED STATES DEPARTMENT OF ENERGY

AUGUST 23, 2001

EXETER

ASSOCIATES, INC.

12510 Prosperity Drive
Suite 350
Silver Spring, Maryland 20904

Commonwealth Edison Company

ICC Staff ML First Set of Data Requests
ICC Docket No. 01-0423
Response to ML1.1
Attachment 3

Embedded Calculation of High Voltage Deliver Service Credit
Calculated Based on Data for the Over 10,000 kW Customer Class

Distribution Facilities Costs:		
Customer Class (I)		
HV ESS	$12,825,925	a
High Voltage Distribution Substations	$11,417,015	b
High Voltage Distribution Lines	$3,068,007	c
Distribution Substations	$4,784,037	d
Distribution Lines	$29,148,828	e
Line Transformers	$3,302,755	f
Total Distribution Facilities	$64,546,567	g = total of a through f
Customers with incoming voltage 69 kV or higher		
HV ESS	$12,825,925	h = a
High Voltage Distribution Substations	$105,689	i = b * y / (x + y)
High Voltage Distribution Lines	$1,510,827	j = c * w / v
Distribution Substations	$0	k = zero
Distribution Lines	$0	l = zero
Line Transformers	$0	m = zero
Total Distribution Facilities	$14,442,441	n = total of h through m
Customers with incoming voltage below 69 kV		
HV ESS	$0	o = a - h
High Voltage Distribution Substations	$11,311,326	p = b - i
High Voltage Distribution Lines	$1,557,180	q = c - j
Distribution Substations	$4,784,037	r = d
Distribution Lines	$29,148,828	s = e
Line Transformers	$3,302,755	t = f
Total Distribution Facilities	$50,104, 126	u = total of o through t
Ratcheted Demand (kW)		
Customer Class (2)	27,153,388	v
Customers with incoming voltage 69 kV or higher (2)	13,371,570	w
Customers with incoming voltage below 69 kV	13,781,818	x = v - w
Customers with incoming voltage equal to 69 kV (2)	128,772	y
Distribution Facilities Cost per kilowatt of demand		
Customers with incoming voltage 69 kV or higher	$1.08	z = n / w
Customers with incoming voltage below 69 kV	$3.64	aa = u / x
Difference	($2.56)	bb = z -aa

Notes:

(1) Distribution Facilities Costs for the Over 10,000 kW Customer Class are obtained from ComEd's Embedded Cost of Service Study (ComEd Exhibit 14.1), Schedule 2a, Page 12 of 18.

(2) Ratcheted Demand for the Over 10,000 kW Customer Class and for customers by voltage group in this class during the year 2000 are from the Company's billing system.

ICC Docket No.01-0423
Response of Commonwealth Edison Company
To City of Chicago's Third Set of Data Requests
COC 3.230 through COC 3.241
To Commonwealth Edison Company
Dated July 26, 2001

Pertain to ComEd Ex. 14.0 and 14.1

COC 3.230 Please describe how different types of customers use each of the following substations: "high voltage ESS", "high voltage distribution substations" and "distribution substations."

RESPONSE: A high voltage ESS (Electric Service Station) is a substation used to supply an individual customer from high voltage lines (69,000 Volts and higher). Customers supplied by a high voltage ESS do not use high voltage distribution substations, except for the Electric Service Stations supplied at 69,000 Volts. For customers supplied by a high voltage ESS at 69.000 Volts, power is reduced from 138.000 to 69,000 Volts at a high voltage distribution substation (Transmission Substation).

A high voltage distribution substation, typically designated by ComEd as a Transmission Substation (TSS) or Transmission Distribution Center (TDC), reduces high voltages (69,000 or 138,000 Volts) to a distribution voltage (69,000,34,000 or 12,500 Volts). All customers except for those customers supplied by high voltage Electric Service Stations at 138.000 Volts and above use these substations.

A distribution substation is a location where voltage is reduced from 34,000 or 12.500 Volts to supply distribution circuits operated at 12,500 or 4,000 Volts. This category also includes low voltage electric service stations that supply individual customers from low voltage distribution lines (4000-34,000 Volts), secondary grid and spot network transformer installations, as well as locations with 10,000 kV A or more of distribution transformer capacity that directly supply customers.

COMMONWEALTH EDISON COMPANY

High Voltage Customers Over 10,000 kW
Annual Revenue Responsibility Under Company's
Ratcheted and Unratcheted Rate Design

Ratcheted Rate Design	
32 customers x $450.88 x 12 =	$173,138
32 customers x $1.97 x 12 =	$756
13,371,570 kW x $3.05 =	$40,783,289
13,371,570 kW x $(2.65) =	$(35,434,661)
TOTAL	$5,522,522
Unratcheted Rate Design	
32 customers x $450.88 x 12 =	$173,138
32 customers x $1.97 x 12 =	$756
10,224,419 kW x $3.70 =	$37,830,350
10,224,419 kW x $(2.65) =	$(27,094,710)
TOTAL	$10,909,534
Difference	$5,387,012

COMMONWEALTH EDISON COMPANY

DOE Proposed Calculation of HVDS Credit for Over 10,000 kW Class with Unratcheted Billing Demands

1. Distribution facilities charge revenue under ratcheted rate design for high voltage customers (13,371,570 kW x \$0.40)	\$5,348,628
2. Net unit charge for HV customers with unratcheted billing demands (\$5,348,628 ÷ 10,224,419 kW)	\$0.52/kW-month
3. Total distribution facilities charge revenue under ratcheted rate design	\$47,480,050
4. Low voltage distribution facilities charge revenues under ratcheted rate design	\$42,131,422
5. Low voltage distribution facilities charge with unratcheted demands (\$42,131,422 ÷ 9,984,179 kW)	\$4.22/kW-month
6. HVDS credit with unratcheted billing demands (\$4.22 - \$0.52)	\$3.70/kW-month

COMMONWEALTH EDISON COMPANY

**Annual Revenue Reconciliation for Over 10,000 kW
Class Under DOE-Proposed Rate Design
Based on Unratcheted Billing Demands**

	Billing Units	Rate	Revenues
Customer and metering	1,021	$450.88	$460,348
Metering service charge	1,021	$1.97	$2,011
Distribution facilities charge	20,208,598	$4.22	$85,280,284
HVDS credit	10,224,419	$(3.70)	$(37,830,350)
TOTAL			$47,912,293
Revenues with ratcheted rate design			$47,942,409
Difference due to rounding			$30,116 (0.06 %)

Illinois Commerce Commission
Docket No. 01-0423
DOE Exhibit 1.5

COMMONWEALTH EDISON COMPANY

Annual Revenue Responsibility of Two DOE Laboratories for Major Components of Service Under Company-Proposed Ratcheted Rate Design and Unratcheted Rate Designs Proposed by Company and DOE

	Fermi	Argonne	Total
Company-proposed ratcheted design	$283,835	$216,155	$499,990
Company-proposed unratcheted design			
Revenues	$735,303	$438,888	$1,174,191
Increase over ratcheted design	$451,468	$222,733	$674,201
Percentage increase	159 %	103 %	135 %
DOE-proposed unratcheted design			
Revenues	$367,355	$220,559	$587,914
Increase over ratcheted design	$83,520	$4,404	$87,924
Percentage increase	29 %	2 %	18 %